Decision 04-10-035 October 28, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004)

INTERIM OPINION REGARDING RESOURCE ADEQUACY

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INTERIM OPINION REGARDING RESOURCE ADEQUACY

1. Summary

In this decision we provide definition and clarification with respect to the policy framework for resource adequacy requirements (RAR) that we adopted last January in Decision (D.) 04-01-050.[1] This represents another significant step toward establishing a new resource adequacy regulatory program whose purpose is to ensure that consumers of electricity within the service territories of California's three largest investor-owned electric utilities (IOUs) receive service that is as reliable as reasonably possible, consistent with current technology and economic constraints.[2] In addition, among other things, we revisit the schedule for implementing the 15-17% planning reserve margin (PRM) requirement that we adopted in D.04-01-050. We do so in light of new concerns about the reliability of California's electricity grid in the near term. Finally, recognizing that additional work on RAR remains to be done in the near future, we address the next procedural steps that are required to ensure that a functioning regulatory program for RAR can be implemented during 2005.

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[1] D.04-01-050 has been modified in certain respects by D.04-07-037. Where reference is made herein to D.04-01-050, such reference is to the modified decision.

[2] The three service territories of the IOUs account for 80% of California's electricity usage. (D.04-01-050, Finding of Fact 4.)

2. Background

2.1 The RAR Framework

Since 2002, in the aftermath of the electricity crisis of 2000-2001, California has wrestled with the creation of resource adequacy requirements. Several of the bodies having responsibility for reliable electric service in California have addressed RAR policies for this state, including this Commission, the California Independent System Operator (CAISO), the California Energy Commission (CEC), and the Federal Energy Regulatory Commission (FERC). To date, the process has yielded a determination that California, led by this Commission, should develop these requirements for IOUs, energy service providers (ESPs), and community choice aggregators (CCAs) (collectively, load-serving entities or LSEs) under our jurisdiction. This decision continues our effort to do so in a manner that recognizes the realities of California's existing hybrid market structure.

Among other things, D.04-01-050 adopted key policies for RAR that are applicable to the IOUs as well as to ESPs and CCAs operating within their service territories. The Commission described the concept of resource adequacy and the role of RARs as follows:

> "Resource procurement traditionally involves the Commission developing appropriate frameworks so that the entities it regulates will provide reliable service at least cost. This involves determining an appropriate demand forecast and then ensuring that the utility either controls, or can reasonably be expected to acquire, the resources necessary to meet that demand, even under stressed conditions such as hot weather [footnote omitted] or unexpected plant outages. 'Resource adequacy' seeks to address these same issues. In developing our policies to guide resource procurement, the Commission is providing a framework to ensure resource adequacy by laying a foundation for the required infrastructure

investment and assuring that capacity is available when and where it is needed." (D.04-01-050, pp. 10-11.)

D.04-01-050 adopted the following RAR policies, applicable to the LSEs:

(1) Each LSE within an IOU's service territory has an obligation to acquire sufficient reserves for its customers' load located within that service territory.

(2) Each LSE is subject to a planning reserve margin (PRM) requirement of 15-17% for all months of the year. Each LSE must meet this obligation no later than January 1, 2008 through a gradual phase-in, with interim benchmarks becoming effective in 2005.

(3) Each LSE must forward contract 90% of its summer (May through September) peaking needs (loads plus planning reserves) a year in advance, subject to adjustment if implementation would result in significantly increased costs or foster collusion and/or the exercise of market power in the Western energy markets.

(4) The 5% target limitation on utilities' reliance on the spot market (i.e., Day-Ahead, Hour-Ahead, and Real-Time energy) to meet their energy needs is continued in effect.

(5) The Commission reiterated its commitment that full value be given to the preferred resources identified in the California Energy Action Plan and to the long-term California Department of Water Resources (DWR) contracts.

2.2 Implementing the RAR Framework

2.2.1 Workshops

The principal task at hand is to give effect to the RAR policy framework that we adopted in D.04-01-050. Bearing in mind the critical importance of a reliable electric grid to the well-being of Californians, we intend to implement a comprehensive RAR program during 2005. This requires resolution of several technical, methodological, definitional, and procedural issues. Many of these issues were considered in a series of 11 workshops on load forecasting protocols, resource counting conventions, and other issues, including deliverability.[3] These workshops were conducted by ALJ Michelle Cooke from March 16 to May 26, 2004. The *Workshop Report on Resource Adequacy Issues* (Workshop Report) prepared by ALJ Cooke was issued on June 15, 2004 and served on parties in R.01-10-024 as well as parties in this proceeding. The Workshop Report is included with this decision as Attachment A.

The June 4, 2004 *Assigned Commissioner's Ruling and Scoping Memo* (Scoping Memo) for this proceeding provided for comments and replies on the Workshop Report, and further stated that these would provide the record for an initial decision on resource adequacy issues by the end of the Summer of 2004. (Scoping Memo, p. 5.)

2.2.2 Additional Issues

The July 8, 2004 *Administrative Law Judge's Ruling Requesting Additional Comments on Resource Adequacy Issues* (July 8 Ruling) observed the following regarding the target date for full implementation of the 15-17% planning reserve requirement:

> "In an April 28, 2004 letter to President Michael Peevey, Governor Schwarzenegger indicated that the 'Commission's phase-in date [for resource adequacy] of 2008 is too slow.' President Peevey's response, also dated April 28, concurred with the Governor's

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[3] The workshops were held pursuant to the February 13, 2004 *Assigned Administrative Law Judge's Ruling (ALJ) on the Scope and Schedule of Resource Adequacy Workshops* (February 13 Ruling) issued in Rulemaking (R.) 01-10-024, the predecessor of the instant proceeding. The order instituting this rulemaking (OIR) explicitly provided that this is the successor proceeding to R.01-10-24 and that the record in that proceeding is fully available for consideration in this proceeding. (OIR, p. 25, Ordering Paragraph 3.)

> assessment and indicated that the phase-in 'needs to be accelerated to ensure system reliability.' The Joint Opening Statement of President Peevey and Commissioner John Geesman of the California Energy Commission at the April 30 prehearing conference indicated that 'we will look closely not only at refinement of the existing requirements, but also their acceleration as requested by the Governor.'"

The July 8 Ruling went on to provide notice that in this initial decision on resource adequacy issues, the Commission may address the proposed acceleration of the reserve requirement. It invited comments and replies on accelerating the phase-in of the full planning reserve margin from January 1, 2008 to June 1, 2006. Parties were also invited to comment on how the year-round 15%-17% reserve requirement and the seasonal 90% forward contracting requirement that was also adopted in D.04-01-050 interact.

Finally the July 8 Ruling noted that a June 17 FERC order[4] on a CAISO market design proposal rejected a proposed day-ahead must-offer proposal based on the premise that a day-ahead must-offer would not be necessary if the LSEs are resource adequate. Noting that this Commission's resource adequacy requirements and CAISO Market Design must work together, the ruling requested comments on whether future Commission-approved contracts intended to comply with resource adequacy requirements should include terms and conditions requiring that resources secured to meet the LSE's resource adequacy requirement be available to LSEs to schedule in the day-ahead time frame.

[4] See 107 FERC 61,274.

2.2.3 Comments

A total of 24 parties, including the respondent IOUs, filed comments and/or replies in response to the Scoping Memo and the July 8 Ruling.[5] The following table identifies these parties and the short titles used to refer to them in this decision. It also indicates whether each party filed comments on the Workshop Report ("Workshop Comments" filed July 13, 2004), replies to those comments ("Initial Replies" filed July 27, 2004), comments in response to the July 8 Ruling ("Additional Comments" filed July 22, 2004), and replies to those comments ("Additional Replies" filed July 29, 2004).

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[5] Consistent with earlier practice as permitted by this Commission, DWR submitted comments and replies by memorandums from its California Energy Resources Scheduling unit.

COMMENTING PARTIES

	Party	Short Title	Workshop Comments	Additional Comments	Initial Replies	Additional Replies
1	Alliance For Retail Energy Markets	AReM	X	X	X	X
2	California Independent System Operator	CAISO	X	X	X	X
3	California Wind Energy Association	CALWEA			X	
4	California Cogeneration Council	CCC	X			
5	California Consumer Empowerment Alliance	CCEA			X	
6	City and County of San Francisco	CCSF	X			
7	California Large Energy Consumers Association	CLECA	X	X		
8	California Manufacturers & Technology Association	CMTA	X			
9	California Municipal Utilities Association	CMUA	X			
10	Duke Energy North America	DENA			X	
11	Department of Water Resources	DWR	X		X	
12	FPL Energy, LLC	FPLE	X			
13	Independent Energy Producers Association	IEP	X	X	X	
14	Northern California Power Agency	NCPA	X			
15	Office of Ratepayer Advocates	ORA	X	X	X	
16	Pacific Gas and Electric Company	PG&E	X	X	X	X
17	Powerex Corp.	Powerex	X		X	
18	Southern California Edison Company	SCE	X	X	X	X
19	San Diego Gas & Electric Company	SDG&E	X	X	X	
20	Sempra Energy Global Enterprises	SEGE	X			
21	Silicon Valley Manufacturing Group	SVMG	X			
22	California Department of Water Resources, State Water Project and the State Water Contractors	SWP / SWC	X			
23	The Utility Reform Network	TURN	X	X	X	X
24	Western Power Trading Forum	WPTF		X		

2.2.4 Phasing of Resource Adequacy Issues

As we discuss in Section 4 of this decision, additional steps are required to ensure that a functioning regulatory program for RAR is in place in 2005. We designate those next steps Phase 2 of the resource adequacy track of this rulemaking. Issuance of this decision represents completion of Phase 1 of the resource adequacy track.

3. Phase 1 RAR Issues

The Workshop Report documents a wide range of consensus and disputed topics. Moreover, the comments on the Workshop Report revealed that consensus was tenuous on many topics, since parties chose to qualify their endorsements with variants upon the consensus or even entirely new suggestions. In addition, the comments and reply comments highlighted at least one topic that several parties feel was not well addressed in the workshop discussion at all.

3.1 Nature of the Obligation to be Satisfied

D.04-01-050 clearly established the obligation for LSEs to acquire resources to cover peak loads plus 15%-17% planning reserves. In addition, the Order provided for a 90% forward commitment for each for each of the summer months of May through September. While D.04-01-050 did not require a 90% forward commitment for the non-summer months, we clarify here that the 15-17% planning reserve requirement applies to the entire year. Indeed, anything short of a year round reserve requirement would constitute sub-optimal and inadequate assurance of grid reliability.

In identifying the workshop issues, the February 13 Ruling raised the issue of how peak loads, which are the basis for the obligation of 90% forward commitments, were to be defined. Several parties in the workshops, and AReM in its comments, raised the question of whether the obligation was for the peak hour alone or some series of hours at and near the peak of each month. CAISO in its reply comments suggests that the obligation be for those hours in which load is greater than or equal to 90% of peak load. Examining historical data, CAISO identifies a range of 10-12 hours per year in which system load is 90% or greater of the absolute peak for that year.[6]

The issue of whether the obligation is based on a single peak hour versus multiple hours at or near peak is closely related to the issue of eligibility for energy limited resources or demand response. Parties agree that these resource types should not be eligible unless they meet minimum numbers of hours per month or per season. It makes no sense to discuss whether resources ought to be eligible to satisfy a planning reserve margin and a forward commitment obligation which have limited hours of operation unless we understand how those constraints match the load curve. Moreover, we are concerned that using an approach that fails to reflect the LSE's load shape could lead to inappropriate cost shifting. Thus, we will require that LSEs acquire a mix of resources capable of satisfying the number of hours for each month that their loads are within 10% of their maximum contribution to monthly system peak. To provide guidance about the general number of hours to be expected in each month, we ask that the CAISO repeat its analysis of historical data provided in Appendix G of the Workshop Report for each month May through September.

In Phase 2, we will flesh out the details of what is necessary to satisfy this requirement. In general, we intend that each LSE must show that it has acquired

[6] Workshop Report, Appendix G.

resources that satisfy a series of loads of that LSE for each month. The resources that "stack up" to satisfy load and the 15-17% PRM for each hour of a month can be different. The resources that "stack up" to satisfy loads plus 15-17% PRM for the different months can also be different. In effect, LSEs are given flexibility to cover the load plus reserves requirements. We expect that LSEs can use this flexibility to find portfolios of resources that match their loads and that do so at least cost, while ensuring that collectively sufficient resources are available to satisfy reliability requirements for the entire control area.

3.2 What Does "Year-Ahead" Mean?

The requirement that LSEs make forward commitments a "year in advance" has been interpreted in three different ways:

- May of 2005 for May-September of 2006, etc.
- Rolling 12 months ahead, e.g. May 2005 for May 2006, etc.
- December 31 of 2005 for May – September 2006, etc.

Parties express support for all three options. Most parties support the December 31 option, generally relying on the rationale that loads will be known more precisely the longer one waits to make load forecasts. A few parties support the rolling 12-months-ahead option, using the same reasoning but while strictly applying the "year in advance" requirement. The CAISO is the strongest supporter of the May of each year for May - September of the subsequent calendar year.

We are persuaded that a fourth option is preferable because it strikes the best balance among competing concerns. We require that "year in advance" compliance filings be submitted on September 30th of each year ahead of the subsequent year's May through September period. The September 30th date is far enough in advance of the next year's peak summer period to provide the

Commission and other parties adequate notice of any shortages or other concerns and to allow the Commission to act on them. Yet the date is late enough in the year to enable a more meaningful preparation and evaluation of forecasts that reflect, among other things, the assignment of load requirements to individual LSEs and necessary contracting arrangements.

We recognize that requiring compliance filings on September 30, 2005 may be problematic if issuance of the Phase 2 resource adequacy decision (see Section 4 of this decision) is delayed beyond our current expectations. Therefore, for the first round of compliance filings made for May – September 2006, we provide that such filings are due on the later of September 30, 2005 or 90 days after the date of the Phase 2 decision. We note that since today's decision establishes the broad outlines of the requirements, LSEs can begin taking compliance actions now.

We would also like to leave open the possibility that we could move to a definition of "year-ahead" in the future that is the rolling 12-months ahead, as suggested by some parties here. Such a definition would be compatible with the existence of a fluid capacity market, which does not yet exist in California, but which we are interested in exploring and developing in the future. When we are further along in our examination of whether and how to facilitate capacity markets, we will consider moving to the rolling-12-month definition for compliance with the year-ahead planning reserve, either in the second generation of this proceeding or some other related proceeding.

3.3 PRM Phase-In Schedule

D.04-01-050 adopted the goal of achieving the 15-17% PRM by 2008, with a gradual phase-in beginning in 2005. The Workshop Report describes several phase-in options that were discussed, including equal increments each year between 2005 and 2008, a "slow at first then fast at the end" approach, and even an acceleration to achieve 15% before 2008. While the workshops were underway, Governor Schwarzenegger sent a letter to President Peevey that, among other things, urged that implementation of the PRM goal be accelerated to 2006. The July 8 Ruling notified parties this proposal would be considered, and it solicited comments from parties about an accelerated phase-in option that would achieve full implementation of the 15-17% PRM by June 1, 2006.

Parties are highly divided on this issue. SCE, PG&E, CLECA and AReM are opposed to accelerating the phase-in and suggest keeping the January 2008 implementation date in place. These parties all note the possibility that legislative action will create a core/non-core market design, and that resources acquired to serve what is now bundled customer load may prove excessive if significant load shifts to non-core status. ORA, IEP and WPTF suggest accelerating the requirement to 2006. TURN opposes accelerating a one-year time horizon and urges that a multi-year time horizon be adopted instead. SDG&E and PG&E note that before such requirements could be imposed, the three IOUs need expanded authority to procure resources, sufficient lead time to conduct analyses and procure needed resources, and assured cost recovery in the event resources prove to be in excess of bundled customer requirements.

CAISO notes that while it supports a June 2006 requirement for the 15-17% PRM requirement, it is not likely that all of the rules will be in place by spring 2005 that would permit LSEs to file complete compliance packages demonstrating that qualifying capacity from eligible resources that conform to deliverability requirements has been acquired. CAISO appears to suggest that we accelerate the requirement to June 2006, but indicates that we should not expect full compliance, at least in terms of analytic rigor, and perhaps in terms of actual resources under the LSEs' control. CAISO expects that a complete compliance package for 2007 can be filed in spring 2006.

We concur with Governor Schwarzenegger that maintaining and enhancing grid reliability in the near term by accelerating the PRM requirement is of overriding importance. D.04-07-028 issued earlier this year in this docket demonstrates our concern about near-term reliability. We acted to approve various demand response programs and to secure scheduling of resources more readily useful to the control area operated by CAISO out of concerns for reliability in Summer 2004. Every year of load growth will stretch resources even more tightly. California Energy Commission (CEC) projections show that considerable generating facilities will continue to come on line through 2006, but retirements of aging power plants without long-term contracts is a continuing threat.[7] We believe that action to improve this situation is needed, but such actions should not lead to stranded costs for IOUs and bundled service ratepayers.

We therefore adopt June 1, 2006 as the date to achieve full implementation of the 15-17% PRM. We are mindful of the caution CAISO has raised about the feasibility of fully satisfying long-term resource adequacy requirements for this date. As discussed further below, in Phase 2 we direct parties to develop a package of reporting requirements and an initial filing date that reveals resources under the LSEs' control for 2006. We expect that the second year's filing requirements, i.e. September 2006 filings for Summer 2007, may be enhanced to more fully reflect our long-term resource adequacy requirements.

[7] CEC, Revised California's Summer 2004 Electricity Supply and Demand Outlook, July 2004, CEC Pub. No. 700-04-005, p. 6.

Adoption of June 1, 2006 as the target date for full implementation of the 15-17% PRM obviates any discussion or schedule for a phase-in through annual increments of reserves; the goal must be achieved in less than 24 months. LSEs, including the utilities and ESPs, will need to act with deliberate speed and intention to achieve this goal, which is necessary to maintain the reliability of our state's electric system.

In this decision, we set forth a variety of regulatory mandates and requirements intended to promote increased and retained supply for the near future, and to set up a robust structure for the longer term. The decision, along with AB 57 and other statutory and regulatory actions, gives regulatory clarity to the market, will lead to revenue adequacy for suppliers, and will provide stability to utility and other load serving entities. All of these outcomes benefit the public by promoting reliability.

At the same time, we cannot neglect our other primary public duty: protection of ratepayers from excessive charges. Increasing supply will cost money, and ensuring reliability does not come cheap. We understand the need to provide mechanisms to pay competitive market costs to new and continuing suppliers. However, we will not "pay any price" or require utilities to sign contracts that meet these requirements at any cost.[8] The memories of the 2000-2001 energy crisis are still fresh in our minds, and the fallout and tremendous costs of that time continue on. We recognize that there is a difference between competitive market costs and prices that arise from the exercise of market power.

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[8] We have already provided that the "90% year-ahead" contracting requirement is subject to adjustment if implementation results in either significantly increased costs or fosters collusion and/or the exercise of market power. (D.04-01-050, p. 11, Footnote 10.)

We will develop reporting requirements in Phase 2 that enable us to monitor the terms and prices of contracts signed under the provisions of this decision to ensure that they are reasonable and that the extra capacity and reliability provided by our reserve requirement is available at reasonable cost to ratepayers.

3.4 Load Forecasting Protocols

The workshop report notes many issues associated with load forecasting protocols. We review each of them in turn.

3.4.1 Coincidence Adjustment

The principal contested issue is whether the obligation should be the LSE's own peak or the LSE's loads at monthly system peak. The difference reflects the degree of coincidence that each LSE's own peak has with the overall system peak. Most parties support defining forward obligations on the basis of coincident loads. We will require that a coincidence adjustment of each LSE's load forecasts be conducted as generally described in the workshop report, and that the resulting LSE load at the time of monthly system peak be the basis for forward commitment obligations.

Conducting a coincidence analysis requires that LSEs provide their own hourly load forecast and that an entity process this data to determine both the control area hourly loads and each LSE's contribution to control area aggregate loads. The CEC has expressed its willingness to undertake this task, and we therefore direct all LSEs to file hourly load forecasts with the CEC. Further, we will require that all LSEs file their historic hourly loads for the preceding calendar year when they submit a load forecast so that the CEC may readily determine how loads may have changed, in both aggregate characteristics and hourly patterns. The schedule and confidentiality arrangements under which the

CEC performs this activity and provides adjusted load forecasts to each LSE will be finalized in Phase 2.

3.4.2 Basis for LSE Load Forecasts

The Workshop Report and the comments reveal that there is no consensus on whether LSE load forecasts should be prepared assuming current customers, current customers and their load growth, or a realistic forecast of loads based on the LSE's best estimate of its future customers.

The comments of the IOUs reveal their concern that ESPs will somehow game these load forecasts and that IOUs will be left with costly obligations as a result of such behavior. Gaming is always a possibility, but we are not persuaded that manipulating load forecasts one year ahead is a major danger. We want these resource adequacy forward commitments to be made in the context of the LSE's own procurement efforts, and not some separate side requirement that does not connect to the realities of procurement. We therefore direct all LSEs to prepare load forecasts on the basis of their best estimate of future customers and their loads. We intend to aggressively pursue an approach that yields accurate load forecasts by all LSEs. We will establish a tracking system that compares forecasts with actual loads and creates penalties for excessive deviations. LSE forecasts that assume or reflect significant load reductions will be subject to rejection or a requirement for additional justification.

To create initial safeguards against gaming, we will request that the CEC review LSE load forecasts in light of the historic loads of each LSE, and compare the aggregate of the LSE load forecasts to independent service area and control area load forecasts available to the CEC (either its own or those of CAISO). To facilitate this, we direct the LSEs to provide to the CPUC and the CEC, along with their forecasts based on best estimates of future customers and their loads, an up-to-date accounting of their current customers and loads. We request that the CEC make an assessment based on all available information at their disposal, and bring obvious discrepancies to our attention for further investigation. We further request that CEC do so well in advance of the September 30 compliance filings by the LSEs. If patterns of systematically low load forecasts are revealed by CEC analyses, we will take appropriate action at that time.

3.4.3 Protocols for Forecasting Loads

Appendix B of the Workshop Report identifies many non-controversial details that are crucial to the development of LSE load forecasts and indirectly affect the resources to cover those loads and the reserves that ensure system reliability. Examples are reporting load forecasts in average mWh for each hour for the five summer months, reporting load forecasts for each IOU service area if an LSE has loads in more than one IOU service area, and presuming weather that reflects 1:2 peak load conditions for each month. Where not specifically modified in this interim opinion, we accept the recommendations included in Appendix B of the Workshop Report.

3.4.4 Nature of Losses to be Included

The few parties who submitted comments on this esoteric issue were surprisingly divided on their views about which losses to include when preparing load forecasts. Since we view resource adequacy as closely aligned with planning and procurement activities, we will require that LSEs include all losses in their load forecasts. This includes distribution losses, transmission losses, and appropriate estimates of unaccounted for energy. As SCE notes, it may be necessary to devise a methodology that LSEs should use in preparing their load forecasts. Such an agreed upon methodology is what was developed and has been used for distribution losses since 1998.

We direct that this topic be included in Phase 2 as a follow-up item. As a starting point for these discussions, we direct SCE to prepare and submit a proposed transmission loss methodology in accordance with Phase 2 procedures to be established by the Assigned Commissioner or ALJ.

3.4.5 Energy Efficiency Impacts

While we are gratified that no party opposes inclusion of committed energy efficiency program impacts in LSE load forecasts, we note there are differences among parties about what constitutes commitment and what data must be available to allow accurate estimates of impacts to be prepared. TURN, PG&E and AReM have made useful points that we build upon. We note that the requirements we describe below are more stringent than those which may have been used in the past because we are addressing load forecasts that are hourly and specific to the months of May through September. Annual averages and non-time differentiated analyses are not sufficient for this resource adequacy purpose.

We agree that reduction of load forecasts from the impacts of committed programs involves two dimensions, both of which are necessary components of our adopted requirements. First, there must be assurance that a program will take place either through funding authorization or a contract between parties. Second, a program must be sufficiently fleshed out so that impacts can be assessed. This requires specification of the time period most affected through a program design that allows an identification of the end-uses and the likely pattern of hourly impacts, and a rollout schedule to permit quantification of monthly impacts.

This guidance must be supplemented by further effort among the parties to develop accurate energy efficiency program estimates applicable to each LSE. We recognize that LSEs are not necessarily the operators of energy efficiency programs, and that the LSEs need to acquire information from program operators and evaluators that will permit reasonable estimates of impacts for each LSE's customers. Our energy efficiency rulemaking and its oversight of measurement and validation activities should ensure that the information needs of individual LSEs discussed here can be satisfied in a timely manner. We intend to pursue further elaboration of these efforts in Phase 2.

3.4.6 Inclusion of Distributed Generation (DG)

Again, no party disputes that customer-side-of-the-meter DG impacts are appropriately subtracted from load forecasts. SDG&E notes that nameplate ratings are not an accurate guide to these impacts. Instead, what is important is the output that these DG facilities are actually producing. As discussed above regarding energy efficiency, what is most desirable is to be able to determine when DG facilities are producing energy so that hourly load impacts can be deducted from LSE hourly load forecasts for each month. Thus, typical patterns of energy production by classes of customers must be developed. We commend this to Phase 2.

3.4.7 Inclusion of Demand Response

In discussing treatment of demand response, we include the traditional emergency curtailment programs, the new price responsive demand programs and tariffs being developed in R.02-06-001, and other programs such as the DWR/CPA Demand Reserves Partnership. The issues associated with energy efficiency, i.e., determining what is committed and whether the design of programs is sufficiently clear that accurate load impacts can be estimated, are also associated with demand response. Demand response, however, has the additional issue of whether the impacts, once quantified, are to be considered as a load reduction or carried on the books as a resource satisfying load. PG&E proposes the former, numerous parties support the latter, and AReM and CCEA support debiting committed non-dispatchable impacts from loads while carrying dispatchable impacts as resources.

We agree that non-dispatchable programs and tariffs, such as the impacts of real-time price tariffs, must be treated as debits from load forecasts. LSEs do not control these impacts once the capability has been developed through marketing and recruitment. LSEs merely estimate the impacts that might be expected as they do for a myriad of other factors affecting loads. It also seems reasonable that if the IOU, or more broadly the LSE, has control over whether a demand response program is dispatched, then these programs are comparable to other resources. Such an LSE needs to decide when such resources might best be used, gauging how these will perform compared to other options. We adopt the position advocated by CCEA.

3.5 Resource Counting Conventions

Resource counting conventions are the means by which resources are determined to be eligible as qualifying capacity that satisfies our forward commitment obligation, the precise formulas for counting various classes of resources, whether there must be limits on the aggregate amount of particular resources that are not available to perform whenever needed, and other issues.

3.5.1 General Formulas for Determining Qualifying Capacity

Qualifying capacity is the term used to describe the actual MW for a specific resource from any one class of resource that may be counted toward the aggregate forward commitment obligation. Section 5 of the Workshop Report provides a series of formulas generally agreed to by the parties for computing qualifying capacity for each class of resource. We endorse the general approach of beginning with net dependable capacity and making specific adjustments appropriate to that class of resource. Unless specifically addressed in the remainder of this decision, we accept the formulas included in Section 5 of the workshop report as written.

A key issue is whether resources in general (excluding demand response that we have decided to carry as a resource) should have their previously adjusted net dependable capacity reduced by a class-specific forced outage rate in determining qualifying capacity. The great majority of parties oppose a further adjustment for forced outage rates on the grounds that this is contrary to conventional practice in resource accounting, and that the planning reserve margins of 15-17% that we adopted in D.04-01-050 already include assumptions about average forced outage rates. We wish to retain the conventional resource counting practices to the extent compatible with our resource adequacy needs, and see no reason to shift forced outage treatment from a broad planning reserve margin issue to a resource-specific, or even resource class-specific, derate to determine qualifying capacity. We conclude that the general formulas for qualifying capacity should not be further adjusted for forced outages at this time. As part of our "second generation" of RAR, described in Section 4, we will evaluate whether the use of unit-specific differential adjustments from the average forced-outage rate would provide cost-effective incentives for generators to make investments to improve performance.

3.5.2 Contracts with Liquidated Damage Provisions

Intra-control area system contracts (e.g., firm contracts with portfolios rather than specific units) have been included for years in planning efforts even though there is no specific unit backing up the contract and the buyer relies upon liquidated damage provisions as compensation for performance failure. Parties propose a variety of ways in which these contracts ought to be treated individually and in the aggregate. AReM, SEGE, and SDG&E support counting existing contracts at full value, without limit, along with continuation of this practice. SCE, IEP, CA ISO and Powerex support full value for the existing contracts, but agree that these should be phased out over time. ORA, TURN and PG&E support counting current contracts at full value, but agree that a cap of about 25% of load should be imposed to limit the exposure that these contracts represent for the system.

We agree that these contracts have been and are being used, and that they provide economic value. Furthermore, to the extent that these contracts are backed by portfolios of generating units, they may be more reliable than unit-specific contracts. We cannot entirely disallow their use, and no party supports such a decision. In addition, there are no close substitutes for these contracts available on the market at this time. However, in addition to the concerns about reliance upon financial compensation rather than physical performance, they have the same issues of uncertain deliverability that we address later. They also make it more difficult to ensure that capacity resources are properly counted and not double-counted. In Phase 2, we will review proposals for contract language or other contract methods that can substitute for liquidated damages contracts, and we will explore whether audit methods can be developed that would allow us to place greater confidence in relying upon liquidated damage contracts.

3.5.3 Wind and Solar Without Backup

As a preliminary matter, and as explained in the Workshop Report, the issues of determining qualifying capacity for wind and solar without backup are inherent issues of the technologies and the sites in which these technologies are located. These issues are not associated with the classification of these resources as qualifying facilities or as renewable generation compliant with Renewable Portfolio Standards (RPS) requirements.

How to treat wind and solar resources without backup is a contested issue for which the workshop process yielded no consensus. Moreover, none of the methods identified in the workshop report (even as augmented by the comments of the parties) leads directly to ready-to-implement rules for treatment of these resources.

Most of the comments support a method that relies upon historic performance, while ORA and CalWEA support using the Effective Load Carrying Capacity (ELCC) adjustment to net dependable capacity. There is considerable variation among parties supporting use of historic performance about how to compute this. We are persuaded that we should not be changing methods based on new versus old facilities except to the extent that specific data for new facilities leads to this conclusion.

We select the historic performance approach, but require that it be determined in such a way as to reveal monthly differences in performance. Further, we require that historic performance be computed over the QF Standard Offer 1 (SO 1) on-peak period only. Finally, we are open to segregation of performance by different wind resource area, but require any party proposing this to provide persuasive data supporting this approach. Since we do not wish this detail to distract us from implementing the first generation of these requirements, we will review any proposals for different treatment of wind resources as part of the second generation of these requirements.

3.5.4 Treatment of Qualifying Capacity for QFs

The Workshop Report identifies the problem that qualifying facilities (QF) are represented most commonly by actual performance, and that some QFs share unit capacity with onsite loads, so that starting from net dependable capacity may not be feasible. Making adjustments creates additional complications that we seek to avoid. QFs have contractual incentives to be online during peak periods, so we direct that QF qualifying capacity use historic performance at peak as noted by the Group B table on p. 26 of the Workshop Report. Adjusting historical performance data to take forced outages into account would be administratively burdensome. We will not adopt such proposals.

3.5.5 Treatment of Energy-Limited Resources

The Workshop Report describes a consensus that energy-limited resources should not be eligible to provide qualifying capacity unless they meet a minimum level of performance. Two requirements were proposed. First, a unit must be able to operate for four (4) hours per day for three consecutive days. In addition, the unit must be able to run a minimum aggregate number of hours per month based on the number of hours that loads in the control area exceed 90% of peak demand in that month. The Workshop Report provides CAISO's estimates of such hours for each month based on data from 1998 through 2003. In their comments on the workshop report, the overwhelming majority of parties support this consensus.

We agree that resources must perform to some minimum level in order to qualify to meet resource adequacy requirements. Resources that are so limited in their flexibility that they do not meet such minimums should not be counted upon as capacity even if they still retain some value for the energy they can produce. A generating resource may not be eligible to satisfy resource adequacy requirements unless it meets the two tests described above. The 90-percent rule was developed in the context of a summer requirement. Therefore, the application of this rule should be limited to the summer months. The development of an appropriate rule for energy-limited resources for non-summer months should be discussed in Phase 2.

3.5.6 Treatment of Demand Response

Demand response has two fundamental issues that we address here: (1) whether to include it as a resource and how, and (2) determining the amount that can be included as qualifying capacity.

Earlier, we decided that demand response should be split between those non-dispatchable programs and tariffs that ought to be debited from load forecasts and dispatchable resources which will count as qualifying capacity. We believe that demand response considered as a resource should not be penalized simply because it is not debited from load forecasts. Thus we direct that reserve requirements should not be imposed for demand response counted as resources. In other words, we do not impose reserve requirements on reserves.

In determining the amount of demand response that can be counted, the workshop report addresses the issue of what demand response resources ought to be eligible to be considered qualifying capacity. This is essentially the same issue as described above for generating facilities. The report describes a consensus among parties that demand response resources must be able to operate a minimum 48 hours per summer season in order to count as qualifying capacity. However, parties did not agree on other facets of what constitutes minimum performance.

An approach supported by ISO, PG&E and TURN is to allow demand response resources that operate only 2 hours per day to be eligible, but to constrain the aggregate amount of these to a small amount. Appendix G of the Workshop Report identifies a proposed limit of 0.89% of monthly peaks. Apparently, this proposal is intended to recognize that even demand response programs with substantial operating constraints have value if they are limited in scope and not expected to cover loads too much beyond the monthly system peak. Other parties reject this proposal, although IEP seems to want to impose a stronger requirement while SDG&E and SCE seem to want a weaker requirement.

We are strongly supportive of demand response in concept and we are willing to create special rules that permit it to qualify provided that we do not endanger system reliability in doing so. The consensus proposal to allow a special demand response minimal seasonal performance level of 48 hours is consistent with our support. Imposing a limit of 0.89% of monthly system peak for 2 hour resources seems to be reasonable as an encouragement for demand response resources that are flexible. We direct these limits be imposed on what qualifies and how much in aggregate may satisfy each LSE's monthly peak.

Lastly, we address how demand response programs are to be quantified as qualifying capacity. A complete answer to the problem is not provided in the record before us. Since most of these programs are new, imposing a quantification standard that relies strictly upon historic evaluation data for each program would be problematic. We will allow these programs to be quantified using comparable evaluation data from similar programs, whether conducted in California or outside of California. We direct the inter-agency staff team supporting R.02-06-001, or its successor, to assist in developing and/or reviewing assessments of these programs and developing practical guidelines for these programs and tariffs. As with energy efficiency, we direct participants in R.02-06-001 or its successor to develop measurement and evaluation activities that will provide the data that are needed to permit complete evaluations of demand response programs and tariffs.

3.5.7 Counting Generating Facilities Under Construction

Looking just one year ahead, we expect that LSE reliance on a new resource still under construction to demonstrate compliance will be a rare occurrence. Nonetheless, we must establish conventions for how to treat these generators. The Workshop Report describes the inability of the parties to come to agreement about how to count resources under construction that might become operational just before or during the relevant May to September period, and the comments reflect continuing disagreement. IEP supports use of the developer's commercial operation date (COD). ORA and CAISO support some lag relative to the developer's date to induce caution and allow for project slippage. SDG&E, SCE, SEGE, PG&E, and TURN, and CAISO in its reply comments all support using some version of CEC-determined CODs and supplemental information.

While the comments of PG&E and the reply comments of CAISO are the most helpful, they are predicated on new systems of tracking and publicly disclosing CODs for large projects licensed by the CEC and smaller ones sited through local processes. We believe the databases maintained by the CEC and CAISO are the appropriate foundation for determining CODs. We direct that parties flesh out these proposals in Phase 2. We wish to establish whether the CEC and CAISO are willing to make modifications to track projects more closely and to allow these updated data to be accessed publicly for use by LSEs in their compliance filings.

3.5.8 DWR Contracts

The long-term contracts that were executed by DWR during the 2001 emergency and subsequently allocated to the three IOUs warrant additional consideration.[9] The Workshop Report identifies three options for treatment of these contracts. The first option is to allow the DWR contracts to be eligible as a resource even if certain features would otherwise exclude a non-DWR contract with the same terms and conditions, but then to apply the deliverability screens that will be developed. The second is to accept as qualifying capacity for each IOU the entire amount of the DWR contracts that we have allocated to that IOU regardless of the contracts' actual features. The third is to fully apply the resource counting conventions and deliverability requirements without any special consideration

As a matter of overarching policy, we are unwilling to risk California's grid reliability by ignoring contract features, such as deliverability, that can impact reliability. At the same time, as we have previously stated, we intend to accord full value to the DWR contracts. We therefore select the first option because it gives appropriate weight to both policies. We require that the DWR contracts be eligible, but that their qualifying capacity be determined by application of the deliverability screens that are ultimately adopted by this Commission. We recognize that this approach may result in discounting any

[9] Several proposals regarding the allocation of certain DWR contracts are pending before the Commission at this time. This policy decision regarding the resource adequacy attributes of the DWR contracts is made without prejudice to our consideration of the allocation proposals.

particular DWR contract, and that ratepayers have to pay more to be assured of reliability than they would if it were counted at full value. However, this is a price of assuring the reliability of service that we find to be necessary. We note that as the individual contracts expire, this problem will diminish and gradually disappear.

3.6 Aggregate and Local Deliverability Requirements

Deliverability embodies the concept that a resource can actually serve the load to which it has been linked through contractual or other relationships. We have only begun to confront the issues associated with creating a workable system in which LSEs understand before they contract with a resource whether, or to what extent, that resource is deliverable to the LSE's loads. Since failure to be deliverable obviously undercuts the whole concept of resource adequacy, we will create deliverability requirements even though they will not be complete for some time.

The Workshop Report and comments make clear that most parties support the general concept of the two proposed deliverability "screens" that were proposed by CAISO. These two "screens" essentially allow a within-control-area resource to know that it can be delivered to load within the control area, or an out-of-the-control-area resource to know that it can be imported into the control area. In the first instance, limited transmission capacity under some system conditions may inhibit the ability of all generators in a "generation pocket" to be able to produce their full output. Thus, in these circumstances, our resource adequacy requirements must also include some scheme to ration production capability in addition to the standard resource counting conventions discussed previously. In the second instance, the capabilities of the transmission ties to other control areas may limit what can be imported into the CAISO control area.

CAISO has proposed to conduct a "baseline analysis" that will determine the extent of such constraints in a sufficiently detailed way that LSEs will understand any limitations, and take these into account in developing their compliance filings to demonstrate forward commitment obligations.

Not all parties support a local deliverability requirement. In general, they are concerned with its complexities, the change in the forum in which local reliability is addressed, possible exercise of market power, and the cost shifts that may occur. Nonetheless, local reliability problems exist, as we addressed in a limited, temporary manner in D.04-07-028. A more permanent solution is necessary, and this decision will set in motion a process to create one.

3.6.1 CAISO's Baseline Deliverability Proposal

The Workshop Report provides, as Appendix D, the CAISO's initial proposal for a baseline analysis to develop a deliverability requirement. Through workshop discussions the parties modified this proposal somewhat, but its broad features are largely endorsed in the comments. We support CAISO's baseline analysis proposal, and direct that this be undertaken as part of Phase 2, to begin immediately after this decision is adopted. We request that the CAISO serve an updated description of the proposed baseline analysis, its data requirements, and a schedule for the analysis on the parties within 10 days of the date of this decision.

Since there are various issues that are documented in the workshop report and within the comments of the parties on that report, we comment on these issues as a form of guidance to the parties in the development of this analysis. While we expect the final proposal to adhere to this guidance, we will provide a comment opportunity for parties to raise concerns as part of our review of the final proposal.

Parties seem to agree that some method is needed to identify generation in generation pockets and to allocate limited export capability such a generation pocket to the "aggregate of loads," but there does not seem to be a strong consensus about how this might be done. SCE supports using transmission payments by utilities and generators as the basis for this allocation. SDG&E proposed a more complicated approach using the existence of contract relationships or CRRs. PG&E's approach also involves whether firm contracts exist and transmission payments have been made. While these proposals all need refinement, directing parties in Phase 2 to determine a method based on transmission investments and payments for firm rights seems to be a sensible approach.

Import capacity allocations to LSEs also received no consensus. Parties' comments reveal many disparate ideas ranging from use of firm transmission rights to pro rata allocations among LSEs using historic LSE loads. Rights in excess of an LSE's needs could be sold. We are not willing to provide guidance on the basis of the information at hand. Alternative allocations of import capacity should be the subject of further discussion in Phase 2, and perhaps informed by the baseline analysis that CAISO has offered to conduct.

3.6.2 Local Deliverability Requirements

Local reliability problems have been addressed to date largely through CAISO's Local Area Reliability Service (LARS) process resulting in reliability must run (RMR) contracts. In this mechanism, CAISO determines generators that must be available because of insufficient transmission capacity to bring power into a locale, and these generators are provided with a cost-based contract to assure their availability. The costs of these contracts are paid through CAISO uplift charges paid by all load in the service area of the Participating Transmission Owner.

Creating a local reliability requirement as part of resource adequacy requirements is consistent with our prior decisions, in which we have held that LSEs are responsible for procuring the resources to meet their customers' needs, including local needs. Most recently, in D.04-07-028, we stated that "it is our intention to minimize the use of RMR contracts, and that the utilities should include local reliability in their long-term procurement plans for the purpose of reducing the need for RMR contracts." (D.04-07-028, p. 13.)

On the benefit side, LSEs would have more options than single-year generation contracts to resolve the problem. Longer term contracts would be of interest to generators to provide greater assurance of future revenues. LSEs are in a better position to identify non-generation options that may be cheaper and more environmentally friendly. LSEs that are also transmission owners (PTOs) might be induced to propose transmission upgrades.

On the cost side, an LSE's customers might have to pay more to acquire necessary resources. Certainly LSEs themselves would have higher forecasting and planning costs as a result of efforts to comply with more complex resource adequacy requirements. Arguably, market power might be exacerbated by imposition of these requirements on LSEs who are smaller and less able to resist holdouts for higher prices. Finally, individual LSEs may have problems collectively acquiring generation to address a problem that stems from weaknesses in the transmission system, which is not their "fault."

We are persuaded that the likely benefits outweigh the likely costs. We will direct parties to address the implementation details of a local reliability requirement in future proceedings.[10] We note that although our adopted policy is to minimize reliance on RMR contracts, we expect RMR contracts to remain available in the future, principally as a backstop mechanism to address local market power.

We expect that some of the "deliverability baseline analysis" to be conducted by CAISO with the support of the other parties in Phase 2 will shed light on the conditions that define "load pockets," the geographic scope of these load pockets, and methods for periodically updating the number and extent of them as system configurations and loading patterns change. Once this is complete, the extent to which specific customers reside in load pockets, methods for tracking these customers in customer master files, and other matters associated with implementation of LSE-specific load forecasts can be undertaken. Once LSE-specific load forecasts in load pocket are known, then the timing of LSE procurement efforts to acquire needed resources must be closely coordinated with the expiration of CAISO RMR contracts.

3.7 Month-Ahead Forward Commitment Obligation

Recognizing that further clarification is required with respect to how the year-round 15%-17% planning reserve requirement and the seasonal 90% forward contracting requirement interact, the July 8 Ruling requested that parties comment on whether the Commission should provide LSEs flexibility to pursue

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[10] We recognize that administration of such requirements will impose a new technical workload on this Commission. We are committed to marshalling and maintaining the resources needed to timely and effectively administer local deliverability requirements.

economic purchases in energy markets, but require that they meet 100% of their planning reserve obligations a month in advance. As noted in the ruling, this means that for the five summer months of May to September, each LSE would have to acquire the incremental remaining 10% of forward commitments needed to satisfy resource adequacy requirements (1:2 peak load forecasts plus 15-17% PRM) not already required by the year-ahead 90% forward commitment obligation one month in advance of the operating month. For the seven non-summer months, this would require that 100% of the resource adequacy requirement be satisfied no later than one month-ahead by forward commitment obligations.

3.7.1 Positions of the Parties

CAISO, WPTF, TURN, SDG&E and PG&E generally support the proposal, although for some the support is qualified. SDG&E is willing to have a 100% month-ahead forward commitment obligation as long as it is for capacity only and there is a capacity market that allows capacity and energy to be separated. SDG&E is similarly willing to have a year-round requirement, but would prefer that it be demonstrated annually as part of the year-ahead demonstration for the five summer months. It is unclear whether SDG&E supports this requirement under the specific construct for resource adequacy that we put forward in D.04-01-050, or just under its own proposed CAISO-operated central capacity market. WPTF supports a summer months only forward commitment requirement, and also suggests that it "be demonstrated on a rolling 12-month advance basis."

CAISO observes that there are market-power mitigation advantages to a confirmation that LSEs are resource adequate one month-ahead. CAISO notes that just because there are estimates of plentiful amounts of uncommitted capacity available in spot markets does not mean that that capacity will be bid into spot markets. CAISO also states that there are operational benefits to such a demonstration because if an LSE fails to comply, there are still various options that can be pursued to mitigate the problem prior to the Day-Ahead market. Essentially, CAISO would prefer to have problems revealed a month ahead rather than in the Day-Ahead scheduling or real-time environments. The CAISO supports the year-round aspect of the proposal as a way of helping to ensure that resources are available under all circumstances. For example, it would lead to better coordination for scheduling of generator maintenance and other operational considerations that will help to ensure that capacity is always available.

Parties opposing the proposal separate two of its features: (1) the level of the month-ahead forward commitment for the summer months, and (2) the year-round requirement. ORA opposes both features. ORA suggests that a 100% month-ahead forward commitment is excessive, squeezing out opportunities for lower cost spot market capacity purchases likely to be available because of the diversity among peaking patterns of the IOUs within the CAISO control area. ORA suggests that a 95% requirement may be more appropriate. ORA opposes the year-round aspect of the proposal, suggesting a focus on summer months is sufficient for now.

In voicing their opposition, SCE and AReM identify the same cost concerns stemming from this requirement that are described in D.04-01-050. They also identify operational issues that have not previously been mentioned. For example, AReM alleges that a year-round month ahead obligation shifts from the peaking capacity orientation of the five summer months toward an energy requirement if it is year-round. AReM interprets this: (1) to be a shift from a resource adequacy requirement toward a general forward commitment obligation, thus interfering in an LSE's basic procurement strategy; and (2) as imposing a forward purchase obligation for energy products that do not exist in the market today. Even if there are merits, AReM argues that this topic was not discussed in the workshop process and the mechanics of such a proposal have not been worked out.

3.7.2 Discussion

We establish a month-ahead forward commitment obligation. LSEs must satisfy 100% of the 15-17% planning reserve margin for each month of the year not less than one month ahead. While we institute the month-ahead obligation for reasons of reliability, price stability, and revenue adequacy, we remain open to exploring alternative forward commitment time frames.

Establishing firm requirements of meeting 90% of summer capacity needs a year ahead and 100% firming up of capacity a month-ahead will serve to ensure that sufficient capacity will be available if it is required while allowing LSEs ample flexibility to procure their energy needs economically. In other words, the Commission does not believe that short-term markets should be relied upon for capacity needs, but that short-term markets can be valuable in meeting energy requirements in a least-cost manner.[11]

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[11] A forward commitment for capacity is consistent with our determination in D.04-07-028 to relax the 5% limit of spot market purchases to allow the utilities to procure in a manner that minimizes real-time congestion and ISO related redispatch costs. So long as LSEs have assured sufficient resources in the forward time frame, they can maximize their opportunities in the spot market while minimizing exposure to high prices and volatility.

One recognition of the transition from planning perspective to the operating perspective is the concern that PG&E raised about inclusion of transmission losses in load forecasts. In Section 3.4.4 we directed that all losses and unaccounted for energy be included in total loss factors for year-ahead load forecasting purposes. This reflects the traditional planning practice that we seek to maintain. However, transmission losses and unaccounted for energy are not included in the load schedules that LSEs must submit to the CAISO in the Day-Ahead scheduling process. To reflect this transition from planning to operating paradigm that the Month-Ahead forward commitment obligation embodies, we will explore in Phase 2 whether to direct LSEs to prepare load forecasts with distribution losses only as is customary in the CAISO scheduling process.

We are sensitive to the arguments of SCE and others that forward contracting for capacity does not come without a cost. However, ensuring that 100% of forecasted capacity needs are met a month ahead will serve to reduce the risks of high prices in the short-term markets,[12] and decrease the need to rely on the CAISO's Residual Unit Commitment (RUC) process, which is costly for consumers. Ensuring that sufficient capacity is committed to California should also enable California to avoid costly mechanisms, aimed at ensuring generator

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[12] As AReM suggests, and as CAISO's comments confirm, a 100% of requirements (peak demand plus 15-17% reserves) month-ahead forward capacity obligation has energy implications. It will tie up the energy associated with the generator's capacity until the point at which the LSE actually schedules its loads into the CAISO Day-Ahead market. CAISO reasons that this will mean that generators have energy that can only be sold in spot markets, likely decreasing its price. This reasoning seems correct.

"revenue adequacy," that FERC is otherwise poised to impose on the CAISO market design.

An important benefit of a Month-Ahead requirement is the ability to update load forecasts among other resources whose nature may change. This opportunity can recognize changes in customers served by a specific LSE as DA customers shift, community choice aggregation takes place, etc. These Month-Ahead adjustments to the year-ahead compliance filings will be the basis for the tightest accuracy requirements. In conjunction with tradable contracts with standardized system support features, the Month-Ahead requirement provides flexibility to LSEs.

A policy that provides for sufficient resources through forward commitments is consistent with the policy goals we expressed for price-responsive demand in the EAP and our own decisions such as D.03-06-032.[13] While sufficient supply will be available to the California market, there will be fluctuation in energy prices to which demand can be provided the opportunity to respond. However, a forward capacity obligation should ensure that excessive energy prices will not occur for sustained periods.

Finally, in their workshop report comments, TURN, PG&E and other parties proposed multi-year forward commitment obligations, in addition to the year-ahead requirement that we have previously adopted and the month-ahead requirement that we establish herein. We are inclined to support additional

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[13] The Energy Action Plan establishes a "loading order" preference for energy efficiency, demand response, and renewables to guide choices for the portfolio that satisfies load and reserves.

forward commitment obligations, but we nevertheless conclude that it is premature to adopt any specific multi-year forward commitment obligation.

Since the details of a Month-Ahead forward commitment obligation were not discussed in the workshops, and we have instituted this requirement on the basis of comments/replies to the July 8 Assigned Commissioner Ruling, we direct further discussions about the specifics of this requirement in Phase 2. The monthly due date, the nature of the filing, and possible adjustments to the qualifying capacity conventions that will be used should be discussed in these workshops and specific proposals brought back for our consideration.

Finally, since many parties have noted that these workshops must be completed in a timely manner to allow a fall 2005 annual compliance filing for the May – September 2006 summer months, we will decline the recommendation of several parties to accelerate discussion of a multi-year forward commitment obligation into Phase 2. Multi-year forward commitments remain an important topic, but simply must remain as a "second generation" topic for which we will structure a development process to begin following Phase 2.

3.8 Availability of Resources for System Support

The third topic raised in the July 8 Ruling is whether resources identified by an LSE in satisfying our resource adequacy requirement should be made available to the LSE in the day ahead time-frame. As described in the July 8 Ruling, FERC's June 17, 2004 order rejected the CAISO's development of a tariff featuring a "must offer" requirement.[14] FERC appears to believe the CAISO's

[14] See 107 FERC 61,274.

proposal was premature and better addressed through contractual relationships between LSEs and generators.

3.8.1 Positions of the Parties

WPTF, SDG&E, PG&E, TURN and CAISO express either qualified support or support for variants to the proposal in the Ruling. For example, WPTF returns to the CAISO tariff proposal and the FERC rejection language to suggest that generators with capacity contracts with an LSE satisfying a resource adequacy requirement be obligated to either (1) be scheduled by the LSE in the CAISO's Day-Ahead scheduling process (inherent in such a capacity contract) or (2) bid into the CAISO's forthcoming Day-Ahead market.[15] WPTF is probably correct to note that a generator bidding into the CAISO's Day-Ahead market is not the same as "be[ing] available to LSEs to schedule in the day-ahead time frame." TURN supports a contractual requirement that a generator be required to bid into the CAISO Day-Ahead or real-time markets if not scheduled by the LSE. SDG&E seems to support not only this understanding of a Day-Ahead bidding requirement, but also an even more far-reaching CAISO dispatch opportunity. PG&E also seems to support contractual language giving CAISO direct dispatch control, at least under some circumstances. Finally, CAISO articulates its support for a Day-Ahead bidding requirement if a resource is not scheduled by the LSE controlling its capacity and participation in the residual unit commitment (RUC) process when aggregate resources bidding into the market fail to satisfy load and ancillary reserve requirements.

[15] WPTF Comments, July 22, 2004, p. 13.

SVMG expresses support for an obligation that resources be required to bid into the CAISO Day-Ahead or real-time markets and notes this is an intrinsic feature of its capacity tagging proposal. IEP seems to support a bid-in obligation in the same manner as SVMG.

SCE, AReM and ORA express various degrees of opposition to the proposal. ORA's opposition appears to focus on a misunderstanding of FERC's direction to the CAISO to participate in this Commission's process to resolve the issue. In its comments, ORA expresses support for a flexible offer approach, which CAISO strongly opposes in its reply comments. AReM opposes the imposition of such contractual terms as a requirement, suggesting they would be acceptable as a voluntary feature between LSE and generator. SCE appears to object to a premature adoption of contractual language and suggests that this effort be deferred until after the original scope of workshop topics have been addressed by this Commission.

3.8.2 Discussion

We agree with the general concept put forward by CAISO. It is pointless to create a body of resource adequacy requirements that create contractual obligations for generators to serve load, and then not require generators to do so. Further, adjustment of LSE requirements to base them upon the LSE's share of control area peak demand inherently builds in a concept of "pooling" that this contractual requirement would effectuate. Clearly, the LSE who has a contract with a generator should have first call on that generator, but if the system demands that a generator be called upon for the benefit of the system, then the generator must be required to operate. A sequence of requirements to first be scheduled by the LSE, then to bid into Day-Ahead markets if not scheduled, and then be subject to RUC if the bid is not accepted is appropriate. We adopt this as our policy going forward. Contracts executed after completion of Phase 2 proceedings on this topic should include such provisions in order to be eligible to count as qualified capacity in satisfaction of forward commitment obligations.

The standard terms and conditions applicable to new contracts are the core requirements of readily transferable capacity-only contracts. Some parties advocate the creation of mandatory, centralized capacity markets, but this is infeasible in the time frame for our September 30, 2005 compliance filing. We believe a readily traded capacity contract that parties can voluntarily exchange is a useful first step. Such contracts can address most of the issues parties have raised in terms of the "best estimates" versus "current customer" basis for LSE load forecasts.

Having established a general policy position, we can go no further at this time. No party put forward proposed contract terms and conditions that would allow this requirement to be implemented now. Some parties articulated various concerns about control over particular kinds of resources that must be overcome in order for this construct to be functional. In addition, we recognize that there is a tension between our adopted going forward policy and provisions in certain existing contracts. For instance, in some contracts LSEs have bargained for intra-day scheduling flexibility. A requirement that unscheduled capacity be bid into the CAISO markets could either be in conflict with the rights and obligations of buyers and sellers under such contracts, or render the bargained-for flexibility worthless.

Therefore, we list below a series of issues that illustrate, perhaps not exhaustively, what should be discussed in yet another of the Phase 2 workshops.

- What specific standard language, if any, should be included in future contracts between LSEs and generators that will sufficiently obligate generators to bid into Day-Ahead markets and be subject to RUC and other appropriate processes?

- How to accommodate intra-day scheduling flexibility in existing contracts, and whether and how to accommodate intra-day scheduling flexibility in new contracts, e.g. through "self-provided RUC"?
- What analyses are needed to determine the probability that these terms of a contract will be exercised? What are the key uncertainties that such analyses must evaluate?
- How are unscheduled resources made available to the ISO?
- What CAISO tariff provisions must be established in order to complement the contractual language that we will impose?
- Are there provisions are appropriate to protect energy-limited resources?
- Should demand response and other non-generation resources be subjected to such requirements? If so, to what degree and under what provisions?

3.9 Nature of the Compliance Filings

The Workshop Report documents concern about whether the annual compliance filings will be subjected to reasonableness reviews once filed. The IOUs interpret reasonableness in the sense of prudency reviews, while other LSEs apparently interpret this in terms of an evaluation of whether they have followed the rules. The comments overwhelmingly support creation of *ex ante* guidelines that provide sufficient guidance that LSEs filings do not have to be exhaustively reviewed to ascertain whether the choices made were reasonable. We intend to provide sufficient clarity through guidelines and rules that the review process should ultimately become a simple checklist. With the large number of entities that may ultimately have to comply with these requirements, any other mechanism is neither cost-effective nor sensible. We do not intend to conduct any prudency reviews as part of the annual compliance filings.

3.10 Resource Adequacy Requirements: Capacity v. Energy

In comments on the draft decision, several parties expressed concern that prohibitions and limitations approved herein will have negative impacts on their overall portfolios. In response to these concerns, we clarify here that these requirements are established for purposes of inducing forward commitments with resources that are appropriate to satisfying a 15-17% benchmark for a summer peak capacity metric. Prospective restrictions on liquidated damage contracts, eligibility thresholds that exclude energy limited resources that cannot be available for a minimum number of hours in a month, and other means by which capacity qualifies to cover loads and a 15-17% planning reserve margin are all part of creating a capacity-oriented resource adequacy requirement. Such limitations do not apply to the use of these resources for energy purposes. To satisfy the energy needs of their customers, LSEs may acquire, contract with and make use of resources that do not qualify for these resource adequacy requirements, unless there are other restrictions expressly established in other decisions for other reasons.

4. Next Steps

Decisions on the topics described above have been necessary in order that the remainder of this process be launched down the right path. We recognize that while this interim opinion provides policy guidance, it does not create a complete package of resource adequacy requirement needed for LSEs to procure resources and submit compliance filings that demonstrate that they have satisfied our requirements.

Two forms of activities constitute "next steps" that we now must take. The most immediate is a series of workshops that will constitute the centerpiece of Phase 2 of the resource adequacy track of this rulemaking. The primary objectives for Phase 2 will be (1) establishing for various Phase 1 policies adopted today the implementation details that each LSE needs in order to proceed to acquire resources; and (2) establishing the reporting requirements, review processes, and compliance tools that will shape how LSEs satisfy us that they have acquired these resources. We anticipate that a tangible work product will be the creation of a new general order applicable to LSEs that assembles our RAR regulations into a single source document.

We believe that completion of Phase 2 by mid-2005 is of critical importance, and commend to the Assigned Commissioner and ALJ the establishment of procedures, including workshops, and a schedule to accomplish this objective. This is an ambitious schedule for consideration of many complex technical issues, and we therefore provide that the Assigned Commissioner or Administrative Law Judge may narrow the scope of Phase 2 with respect to individual topics if it appears that resolution of the issues associated with a topic will unduly delay completion of Phase 2.

4.1 Workshops and Other Processes for Phase 2

Broadly speaking, there are two categories of topics that are necessary for Summer 2005 compliance filings for Summer 2006 monthly obligations. The first of these is completion of various load forecasting protocols, resource counting conventions, and deliverability screens to permit implementation by all LSEs. The second is development of the actual reporting requirements, the process by which these filings will be reviewed, and any penalties or sanctions needed to induce full, accurate and timely compliance.

Implementation mechanics topics include, but are not necessarily limited to the following:

- Coincidence and EE/DR impact allocation adjustment methods for each LSE's load forecasts.
- An hourly loss methodology that incorporates distribution and transmission losses and unaccounted energy.
- Procedures for quantifying the hourly impacts of committed energy efficiency and demand response tariffs and programs.
- Methods for determining qualifying capacity of wind and solar without gas backup generators using a monthly, historic performance during the SO 1 on-peak period, methodology.
- Methods for estimating COD dates for generators of all sizes based upon appropriate modifications to existing CEC and CAISO tracking systems.
- Completion of a functional deliverability screening methodology based upon the proposals of the CAISO documented in the workshop report, and its Appendix B, and the specific decisions earlier in this decision. Local resource adequacy requirements, including identification of load pockets, generator performance in load pockets, transmission import capabilities, and various adjustments to the current LARS process that results in RMR contracts,
- Development of (1) standard contract language that will require a generator, if not scheduled by the LSE to serve its own load, to bid into the CAISO integrated Day-Ahead market, and if not accepted there to be subject to the residual unit commitment process (RUC), and (2) a reasonable understanding of the probability that a generator not scheduled by the LSE will actually be selected to operate in the RUC process.
- Alternative forms of contracts for capacity that can substitute for those with liquidated damage provisions and thus satisfy resource adequacy requirements.

Reporting, reviewing, and sanctions topics include, but are not necessarily limited to the following:

- Load forecasting filing requirements, including provision of historic load data, adjustment for coincidence, adjustment for energy efficiency and demand response activities, and appropriate documentation.
- Resource tabulations showing how load forecasts and planning reserve requirements are satisfied for the hours of each month with loads 90% or greater than peak of the month, tabulations of the qualifying capacity of each resource under contract or the control of the LSE that is deliverable to load for each of these hours, and appropriate documentation.
- A review process that assures that each LSE's load forecasts was prepared properly, that resources identified as satisfying each LSE's load and reserve requirements are eligible and deliverable, processes for providing feedback to LSES and opportunities to correct errors and mistakes, and an overall assessment that the collective loads and resources submitted by all LSEs comport with aggregate summer assessments prepared by the CEC and CAISO.
- A system of penalties and sanctions that would motivate LSEs to provide accurate load forecasts and sufficient levels of deliverable resources.
- The specific compliance reporting requirements, review process, and penalties for the Month-Ahead forward commitment obligations, as well as any changes in load forecasting protocols and resource counting conventions appropriate for the short lead time of this requirement.

4.2 Second Generation of Requirements

Beyond Phase 2, there are "second generation" topics that need to be revisited or added to our initial generation of resource adequacy requirements. We note that certain of these topics are necessarily on a slower track for the reasons described herein, and likely will not be completed before the first round of compliance filings are due. We intend that other related topics, particularly proposals related to capacity trading, be considered more expeditiously.

Additional RAR topics that we intend to address include but are not necessarily limited to the following:

- Unit-specific differential adjustments to average forced outage rates,
- Multi-year forward commitment concept, and
- The resource tagging and trading concept.

5. Comments on Draft Decision

On August 31, 2004, the draft decision was filed and served on parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Commission's Rules of Practice and Procedure. AReM, CAISO, Calpine Corporation, CALWEA, CCC, CCSF, CMTA, DENA, DWR, IEP, ORA, PG&E, Powerex, SCE, SDG&E, SEGE, TURN, and WPTF filed comments. AReM, CAISO, IEP, ORA, PG&E, Powerex, SCE, TURN, and WPTF filed replies to comments.

We have made several revisions to the draft decision in response to the comments and replies. Among other things, we have (a) included the entire Workshop Report as an attachment to this decision, (b) made provision for an extension of time for the first-year resource adequacy compliance filings in the event the Phase 2 decision is delayed, (c) clarified our intent regarding the 0.89% limitation on counting demand response for 2-hour demand response products, (d) clarified the discussion of CAISO's baseline deliverability proposal, (e) added to the discussion of the month-ahead forward commitment requirement to indicate our intent to address this requirement further in Phase 2, and (f) added a new section to clarify that resource adequacy requirements and limitations pertain to capacity and are not intended to preclude LSE's from making use of resources for the purpose of meeting the energy requirements of their customers that do not meet resource adequacy requirements.

6. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner. Mark S. Wetzell, Meg Gottstein, and Carol Brown are the assigned ALJs and Principal Hearing Officers in this proceeding.

Findings of Fact

1. Allowing LSEs to acquire a mix of resources capable of satisfying the number of hours for each month that their loads are within 10% of their maximum contribution to monthly system peak gives them flexibility to cover load plus reserves requirements.

2. For purposes of implementing the requirement that LSEs make forward commitments a year in advance of each May through September period, compliance filings made on the prior September 30 will provide the Commission and other parties adequate notice of any shortages or other concerns, yet will enable meaningful preparation and evaluation of forecasts.

3. The July 8 Ruling provided notice that this decision on resource adequacy issues may address the proposed acceleration of the 15-17% PRM requirement, and it invited comments and replies on accelerating the phase-in of the full planning reserve margin from January 1, 2008 to June 1, 2006.

4. Every year of load growth will stretch existing resources even more tightly, and retirements of aging power plants without long-term contracts are a continuing threat.

5. Maintaining and enhancing grid reliability in the near term by accelerating the 15-17% PRM requirement from January 1, 2008 to June 1, 2006 is consistent with the policy to maintain near-term reliability underlying D.04-07-028.

6. The CEC has expressed its willingness to conduct a coincidence analysis based on the LSEs' own hourly load forecasts, and process this data to determine both the control area hourly loads and each LSE's contribution to control area aggregate loads.

7. LSEs will need to acquire information from program operators and evaluators that will permit reasonable estimates of impacts for each LSE's customers.

8. Typical patterns of DG energy production by customer classes must be developed so that hourly load impacts can be deducted from LSE hourly load forecasts for each month.

9. Demand response programs over which the LSE has dispatch control are comparable to other resources.

10. An adjustment for forced outage rates is contrary to conventional practice in resource accounting, and the 15-17% PRM adopted in D.04-01-050 already includes assumptions about average forced outage rates.

11. Intra-control area system contracts with liquidated damage provisions as compensation for performance failure have issues of uncertain deliverability.

12. QFs have contractual incentives to be online during peak periods.

13. Our overarching policy is to avoid the risk to California's grid reliability that is associated with ignoring contract features, such as deliverability, that can impact reliability.

14. Failure of a resource to be deliverable undercuts the whole concept of resource adequacy.

15. Creating a local reliability requirement as part of resource adequacy requirements is consistent with prior Commission decisions, in which the

Commission has held that LSEs are responsible for procuring the resources to meet their customers' needs.

16. A 100% forward commitment obligation for a month-ahead time horizon means that for the five summer months of May to September, each LSE would have to acquire the incremental remaining 10% of forward commitments needed to satisfy resource adequacy requirements, and that for the seven non-summer months, a new forward commitment obligation would be created.

17. A 100% month-ahead forward commitment obligation is intended to ensure that sufficient capacity will be available if it is required while allowing LSEs ample flexibility to procure their energy needs economically.

18. It is pointless to create a body of resource adequacy requirements that create contractual obligations for generators to serve load, and then not require generators to do so.

Conclusions of Law

1. The Commission intends to implement a comprehensive RAR program during 2005.

2. LSEs should acquire a mix of resources capable of satisfying the number of hours for each month that their loads are within 10% of their maximum contribution to monthly system peak.

3. For purposes of implementing the requirement that LSEs make forward commitments a year in advance, we will require that LSEs submit compliance filings on September 30 of each year demonstrating 90% forward commitments for the following May through September period.

4. To maintain and enhance near-term reliability, full implementation of the 15-17% PRM adopted in D.04-01-050 should be reached by June 1, 2006.

5. A coincidence adjustment of each LSE's load forecasts should be conducted as generally described in the workshop report, and the resulting LSE load at the time of monthly system peak should be the basis for forward commitment obligations.

6. LSEs shall file their historic hourly loads for the preceding calendar year when they submit hourly load forecasts so that the CEC may readily determine how loads may have changed, in both aggregate characteristics and hourly patterns.

7. LSEs shall prepare load forecasts on the basis of their best estimate of future customers and their loads.

8. The recommendations for development of LSE load forecasts included in Appendix B of the Workshop Report should be adopted except as specifically modified in this interim opinion.

9. LSEs shall include all losses in their load forecasts, including distribution losses, transmission losses, and appropriate estimates of unaccounted for energy.

10. Load forecast reductions reflecting the impacts of energy efficiency programs should be based on (1) assurance that a program will take place either through funding authorization or a contract between parties and (2) sufficient program detail so that impacts can be assessed.

11. Load forecast reductions reflecting customer-side-of-the-meter DG impacts should reflect the output that these DG facilities are actually producing, not nameplate ratings.

12. Non-dispatchable demand response programs such as real-time price tariffs should be treated as debits from load forecasts, while demand response programs over which the LSE has dispatch control should be counted as other resources.

13. The qualifying capacity formulas set forth in Section 5 of the Workshop Report are accepted except where specifically addressed herein.

14. The general formulas for qualifying capacity set forth in Section 5 of the Workshop Report should not be further adjusted for forced outages.

15. Wind and solar resources without backup should be counted on the basis of historic performance determined in such a way as to reveal monthly differences in performance, and for this purpose historic performance should be computed over the QF Standard Offer 1 (SO 1) on-peak period only.

16. QF qualifying capacity should be based on historic performance at peak as noted by the Group B table on p. 26 of the Workshop Report.

17. A generating resource should not be eligible to satisfy resource adequacy requirements unless it is able to operate for 4 hours per day for three consecutive days and the unit satisfies a minimum aggregate number of hours per month based on the number of hours that loads in the control area exceed 90% of peak demand in that month. For the year 2006, the 90 percent rule shall be enforced only for the five summer months. Its application in future years will be a subject for evaluation in Phase 2.

18. Because demand response considered as a resource should not be penalized simply because it is not debited from load forecasts, reserve requirements should not be imposed for demand response counted as resources.

19. Allowing a special demand response minimal seasonal performance level of 48 hours in conjunction with the 0.89% of monthly system peak limit on two-hour demand resources is reasonable; these limits are therefore imposed on what qualifies and how much in aggregate may satisfy each LSE’s monthly peak.

20. The databases maintained by the CEC and CAISO are the appropriate foundation for determining CODs for resources still under construction.

21. The long-term contracts executed by DWR should be eligible as resources even if certain features would otherwise exclude a non-DWR contract with the same terms and conditions, but the deliverability screens that will be developed in this proceeding should be applied to them.

22. Because we are persuaded that the likely benefits of a local deliverability requirement outweigh the likely costs, we adopt this requirement and direct parties to address the implementation details of a local reliability requirement in future proceedings.

23. A 100% month-ahead forward commitment obligation is adopted for all LSEs.

24. The LSE who has a contract with a generator should have first call on that generator, but if the system demands that a generator be called upon for the benefit of the system, then the generator must be required to operate.

25. We adopt this as our policy: all resources identified as satisfying RAR shall conform to a sequence of requirements to first be scheduled by the LSE, then to bid into Day-Ahead markets if not scheduled, and then be subject to RUC if the bid is not accepted.

26. We do not intend to conduct any prudency reviews as part of the annual or monthly RAR compliance filings.

27. To give effect to the RAR policies adopted in D.04-01-050 and in this decision, a second phase of the RAR track of this rulemaking should be established, consistent with the foregoing discussion.

INTERIM ORDER

IT IS ORDERED that:

1. All respondent utilities, energy service providers, and community choice aggregators are subject to the load forecasting protocols and resource counting

conventions adopted in this interim order as the basis for resource adequacy requirements until directed otherwise by subsequent orders or decisions.

2. Phase 2 of the Resource Adequacy track of this proceeding is established to consider the implementation topics described in the foregoing discussion, findings, and conclusions. The procedures and schedule for Phase 2 shall be those established by the Assigned Commissioner or Administrative Law Judge. The Assigned Commissioner or Administrative Law Judge may narrow the scope of Phase 2 with respect to individual topics if it appears that resolution of the issues associated with a topic will unduly delay completion of Phase 2.

3. This proceeding remains open.

This order is effective today.

Dated October 28, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I will file a dissent.

/s/ CARL W. WOOD
Commissioner

I will file a dissent.

/s/ LORETTA M. LYNCH
Commissioner